Dewadasa, Manjula and Ghosh, Arindam and Ledwich, Gerard (2009) *Foldback current control for a DG to achieve Fast Arc Extinction in a distribution network.* In: Proceedings for the 3rd biennial Smart Systems Postgraduate Student Conference, 16 October 2009, Owen J Wordsworth Room, Queensland University of Technology, Gardens Point, Brisbane.

Foldback Current Control for a DG to Achieve Fast Arc Extinction in a Distribution Network

M. Dewadasa, A. Ghosh, G. Ledwich
Queensland University of Technology, Australia
Jalthotage.dewadasa@student.qut.edu.au

***Abstract*— The distribution network reliability can be increased if distributed generators (DGs) are allowed to operate in both grid-connected and islanded operations when the network has a high DG penetration level. However, the current utility regulations do not allow for the islanded operation. The arc faults are the one of the major issues preventing the islanded operation, since the arc will not extinguish if the DGs are not disconnected.**

In this paper, the effect of a converter interfaced DG on an arc fault is investigated by considering different control strategies for the converter. The foldback current control characteristic is proposed to a converter interfaced DG to achieve quick arc extinction and self-restoration without disconnecting the DG in the event of an arc fault. The results are validated through PSCAD/EMTDC simulations.

Index Terms*— *arc fault, arc extinction, current limiting, foldback current

I. Introduction

Climate change has raised concern about distribution generation (DG) based on renewable energy sources such as wind, solar, mini-hydro, bio-mass, etc. Most of these DG sources are connected to the distribution network through voltage source converters (VSCs) due to the intermittent nature and the requirement of dc to ac conversion. It is cost-effective to supply the rapid growing load demand by connecting DGs near to the load centers rather than increasing the central power generation capacity.

Several issues can be identified after the connection of DGs in to the distribution network. Among them, the capability of sustaining an arc fault by a DG or DGs can be considered as a major issue [1]. The arc faults can be successfully eliminated by de-energizing the line long enough to self extinguish the arc. Then electricity supply can be restored by performing the automatic reclosing. However, arc faults are not extinguished immediately after recloser is opened if DGs are connected to the network. As a solution, DGs are required to disconnect from the network in the event of an arc fault. As per IEEE Standard 1547, DGs have to be disconnected from the electric power system for the faults [2]. The islanding detection methods can be used to disconnect the DGs from the system [3].

In case of high DG penetration levels, the disconnection of DGs for every fault (i.e. permanent and temporary) will drastically decrease the reliability in the system. This is especially true for temporary faults since most of the faults (approximately 90%) in the power system are temporary due to the arc faults [4]. DG benefits can be maximized if DGs can retain connected to the system without sustaining the arc in the event of an arc fault. This is more advantageous when a small portion of the distribution network or a microgrid operates in the islanded mode.

In this paper, foldback current control characteristic is proposed for a VSC to achieve quick arc extinction without disconnecting the DGs in a network. Moreover, the DG has the ability to self-restore the system if the generation is sufficient to supply the load demand. Two converter control strategies are considered to show the effect of DGs on arc faults. The work described in this paper is mainly focused on the converter control strategies, arc fault model selection and system simulations. The proposal is validated by PSCAD/EMTDC simulations.

II. Converter Control Strategies

In this section, two types of converter control strategies are considered for a converter interfaced DG; constant current (CC) and foldback current (FBC). The converters are limited their output current to protect power switches in the event of a fault in the system. This current limiting is usually achieved by switching from voltage control mode to current control mode of the converter. The conventional converters are typically employed with CC control and these converters limit the output current to twice the rated current during a faulted condition. The FBC control is popular as the current limiting protection in most of the bench-top power supplies. In this study, FBC control is implemented for a converter interfaced DG. These CC and FBC controls are considered for a DG to investigate the effect of DG current control strategy on arc fault extinction.

The output characteristic of a converter for CC control operation is shown in Fig. 1. The rated voltage and current are shown by V_r and I_r respectively. The region AB represents the normal operation of the converter in voltage control mode. In this region, converter has the ability to supply its rated power maintaining the nominal voltage. In region BC converter supplies more than the rated current and beyond the point C converter operates in constant current mode by limiting its output current in the region of CD. In this mode of operation, the converter injects twice the rated current (i.e. $2\times I_r$). This constant current operation of the converter can be occurred due to the overloading or faulted condition in the network.

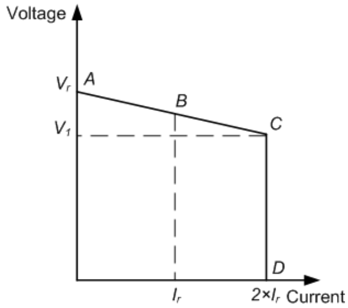

Fig. 1. Constant current control of VSC

The output voltage-current characteristic of the converter for a FBC is shown in Fig. 2. Three regions can be mainly identified; region AC, CD and DE.

- *Region AC* – In this region, converter operates in voltage control mode. The converter has the ability to maintain the nominal voltage at the terminal.
- *Region CD* – This represents the constant current region. The converter terminal voltage can be between V_1 and V_2. Typically, twice of the rated current will be injected by the converter as mentioned above.
- *Region DE* – The converter operates in foldback current control mode, if the terminal voltage is less than V_2. The converter is controlled in the current control mode and the value of injected current will be decided based on the value of the terminal voltage. Therefore, in this mode of operation, the injected current into the network is always less than the value in constant current mode. For example, the point *O* as shown in Fig. 2 can be considered as the operating point during a faulted condition. As a result of lower current injection, power dissipation of the converter can be minimized as well as current contribution from the converter can be reduced in the event of a fault. Thus, the effect of fault current on protective devices from converters can be considered as low. Moreover, fault ride through capability (withstand time for a fault) of the converter can be increased since power dissipation is low during the fault.

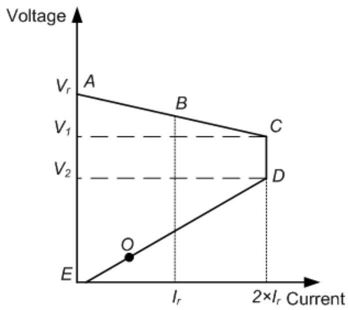

Fig. 2. Foldback current control of VSC

Simplified single phase converter structure which is considered in this study is shown in Fig. 3. A DG source is represented by an ideal DC voltage source V_{dc} while Z_{dg} is the converter source impedance and V_{dg} is the terminal voltage. The current through the inductor is represented by I_{dg}.

Converter controller monitors the output voltage and output current continuously. The output current of the converter can be controlled in current control mode depending on the value of terminal voltage V_{dg}, since the source impedance Z_{dg} is known. The converter control algorithm for the FBC control is shown in Fig. 4. The time period t_1, t_2 and t_3 (10- 20 ms) are selected appropriately to prevent the unnecessary switching between voltage and current control modes due to the transient conditions in the network.

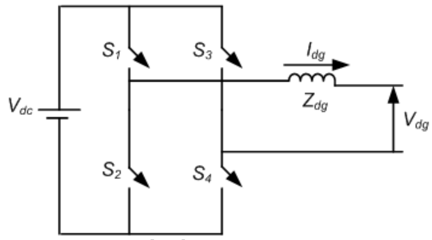

Fig. 3. Single phase converter structure

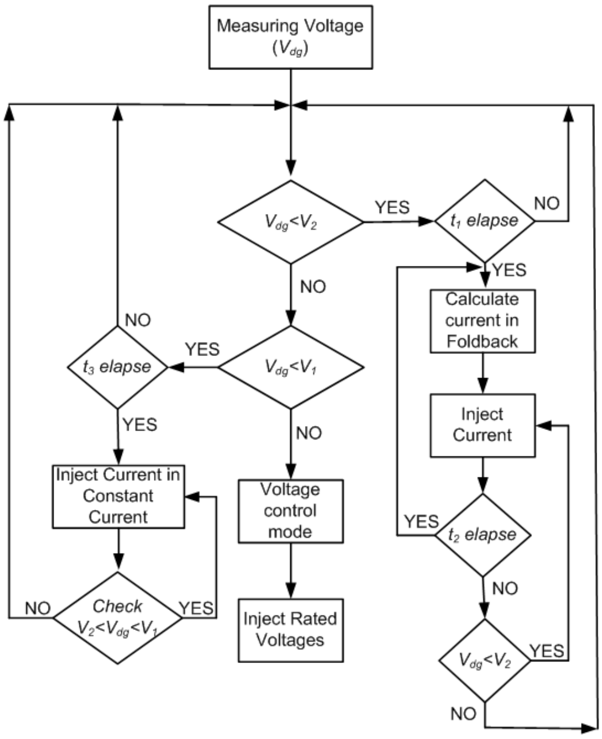

Fig. 4. Flowchart for FBC control of VSC

III. Arc Model Selection for Simulation

Representation of arc faults accurately in simulation will be important for the designing and protection purposes. However, it is a difficult task to reproduce the real arc behaviour by computer simulation due to the extremely random character of the arc. A suitable arc model should be selected to analyze the effect of DGs on arc faults. The selected arc model should be appropriate to analyze a network which has utility and DGs connected during the beginning of the fault and then utility is disconnected and DGs continue the supply to the arc fault. Moreover, the arc model should give an indication whether the fault is sustained or extinguish. One possibility is to choose the current dependent arc resistance model [4]. This arc model can be represented by a time varying resistance or a square wave voltage source which changes its sign with the arc current. The model will be suitable when both the utility and DGs are present in the network. However, after the utility is disconnected, the only source supplying the arc fault current is DGs. Thus parameters of new system have changed and this model is not suitable.

Most of the line faults are single phase to ground and they are temporary. In this case, the faults can be successfully removed by performing the single-pole reclosing in high voltage (HV) transmission lines. The arc can be modeled as primary and secondary considering the single pole reclosing [5] in these HV lines. The primary arc exists before the circuit breaker opens and secondary arc occurs due to the hot plasma remaining from the primary arc after the circuit breaker opens. The secondary arc is sustained by the mutual coupling (capacitive and inductive) between the faulted phase and sound phases [5].

The reclosing is usually three-pole in medium voltage and low voltage systems. Therefore, in a similar way to HV arcs, secondary arc model can be used in the presence of DGs to simulate the arc faults after disconnecting the utility supply. In this case, DGs sustain the secondary arc. In [1], such similar arc fault study has been performed with wind power based DG plant. It has been compared the arc voltage waveforms obtained from measurement and simulation to validate the model. Therefore primary and secondary arc models can be identified as the most suitable model to analyze the arc faults in the presence of converter connected DGs in the distribution network. The primary arc model can be used when both the utility and DGs are present in the network, while the secondary arc model is used after the utility is disconnected and only DGs are connected to the system. The primary and secondary arc model parameters and arc extinction are considered in details below.

A. Primary Arc Model

A long ago, primary arc is represented by an ideal short circuit or a linear low resistor or as a voltage source with periodic rectangular form changing the sign of the wave with arc current. The theory of switching arc is proposed recently to model the long fault arcs in air including both primary and secondary arcs [6]. Heavy fault current flows through during the primary arc period. The arc column has a large cross sectional area since system provides a high input electrical power to the arc. It can be assumed as no elongation of the arc length during this period. The dynamic arc characteristics can be simulated by [5-7],

$$\frac{dg_p}{dt} = \frac{1}{T_p}\left(G_p - g_p\right) \qquad (1)$$

where, T_p is the arc time constant, G_p is the stationary arc conductance and g_p is the instantaneous arc conductance. G_p and T_p can be expressed as,

$$G_p = \frac{|i_p|}{V_p l_p}; \qquad T_p = \frac{\alpha I_p}{l_p} \qquad (2)$$

where, $|i_p|$ is the absolute value of the primary arc current, V_p is the arc voltage gradient, l_p is the primary arc length, I_p is the peak value of primary arc current and α is a constant.

B. Secondary Arc Model

The secondary arc usually extinguishes, however, the duration can depend on many factors mainly on secondary arc current [8]. The secondary arc length can vary with time. Wind velocity and the magnitude and duration of primary arc current are two main factors affect to the elongation of the arc length. The total secondary arc voltage is practically proportional to the arc length [6]. The low current secondary arcs can be simulated [5] by using

$$\frac{dg_s}{dt} = \frac{1}{T_s}\left(G_s - g_s\right) \qquad (3)$$

where T_s is the secondary arc time constant, G_s is the stationary arc conductance and g_s is the instantaneous secondary arc conductance. G_s and T_s can be given by

$$G_s = \frac{|i_s|}{V_s l_s(t_r)}; \qquad T_s = \frac{\beta I_s^{1.4}}{l_s(t_r)} \qquad (4)$$

where $|i_s|$ is the absolute value of the secondary arc current, t_r is the time from initiation of secondary arc, $l_s(t_r)$ is the time varying arc length, I_s is the steady state peak secondary arc current and β is a constant.

C. Arc Extinction

To define the conditions for arc extinction is a challenging task of arc modeling. The arc self-extinction action depends not only on the fault current magnitude, but also on the transient recovery voltage rate after successful arc extinction at the current zero crossing. In addition, the arc extinction time is proportional to the arc time constant. Ref. [5] proposes the arc extinction based on dielectric breakdown, that is the arc extinguishes at each current reversal. The arc model in (3) only considers the thermal re-ignition while dielectric re-strikes are not considered. Some of the models are used the time derivative of the instantaneous arc resistance to determine the arc extinction. In [8], the secondary arc extinction is determined, if the derivative of arc resistance is higher than the value in (5) and the instantaneous conductance is lower than the value (6). However, this criterion only considers the thermal extinction of the arc and there is a probability to dielectric re-ignition of the arc.

$$\frac{dr'_{arc}}{dt} = 20 M\Omega/(s \cdot m) \qquad (5)$$

$$g'_{\min} = 50 \mu S \cdot m \qquad (6)$$

IV. Simulation Results

A simple radial feeder is considered as shown in Fig. 5 to investigate the effect of different DG control strategies on arc faults. The primary and secondary arc models are used to model the arc fault in simulation study. Arc extinction is determined based on (5) and (6) only considering thermal arc extinction. A converter connected DG is connected at BUS-2. The capacity of DG is selected to supply the load demand at BUS-3 in autonomous mode (i.e. in islanded operation without the utility). System parameters are shown in Table I.

An arc fault is created at one of the peak in voltage waveform between BUS-1 and BUS-2. A high fault current can be seen at the beginning since both the utility source and DG feed the arc fault. At this stage, the arc is modeled as a primary arc. It is assumed that the circuit breaker, CB_1, operates by detecting the arc fault after the response time to isolate the utility supply. The arc is modeled as a secondary arc once after the operation of CB_1. As a result of CB_1 operation, the system beyond BUS-1 becomes islanded and fault current reduces to the value which is determined by the converter control in current control mode. The secondary arc length increases with the time and it is mainly depending on the environmental conditions such as wind velocity. In this case, a lower value for the wind velocity is assumed. Simulation results are shown below for the different converter control strategies.

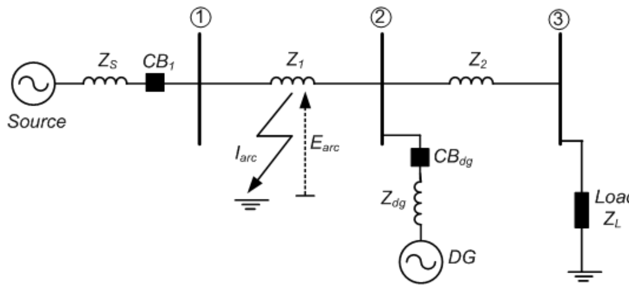

Fig. 5. A radial feeder with DG

TABLE-I: SYSTEM DATA

System data	Value
System frequency	50 Hz
Source voltage (V_s)	11 kV rms (L-L)
Source impedance (Z_s)	0.078 + j 0.7854 Ω
Source impedance (Z_{dg})	0.39 + j 3.927 Ω
Feeder impedance (Z_1=Z_2)	0.585 + j 2.9217 Ω
load impedance (Z_L)	300 + j 18.75 Ω
DG rated current	0.025 kA
Arc parameters	
Primary arc model [6] (with numerical data)	$\frac{dg_p}{dt} = \frac{l_p}{2.85\times10^{-5} I_p}\left(\frac{\lvert i_p \rvert}{15 l_p} - g_p\right)$
Secondary arc model [6] (with numerical data)	$\frac{dg_s}{dt} = \frac{l_s(t_r)}{2.51\times10^{-3} I_s^{1.4}}\left(\frac{\lvert i_s \rvert}{75 I_s^{-0.4} l_s(t_r)} - g_s\right)$
primary arc length (l_p)	0.5 m
secondary arc length (l_s)	*$10\times l_p \times t$ (t - time)*

A. DG with CC Control Strategy

The arc fault is created at 0.305 s between BUS-1 and BUS-2. The circuit breaker, CB_1, responds 0.390 s to isolate the fault from the utility side. The DG limits the output current to twice the rated current during primary and secondary arc period. In this study, the DG current limit is calculated as 50 A (i.e. twice the rated current). The variation of arc voltage, arc current and instantaneous arc resistance during the primary arc period is shown in Fig. 6. It can be seen that higher arc current and lower arc resistance during the primary arc period.

The variation of secondary arc voltage, arc current and arc resistance during the secondary arc period is shown in Fig. 7. The arc resistance increases when time elapses due to the arc length elongation as shown in figure. The arc current remains same until the arc extinction occurs since the DG injects constant current during the fault. However, arc voltage rises with the time as a result of constant current injection of the DG through the increasing arc resistance. Finally, the arc extinguishes at 1.0 s. The arc voltage and the arc current at arc extinction are shown in Fig. 8. The secondary arc duration can be calculated as 0.61 s. It indicates that arc can extinguish after a time period of 0.61 s once the utility side breaker opens, even if DG is not disconnected from the network. The time duration for the arc extinction can change depending on the prevailing environmental conditions. The output voltage and current of the DG during the fault is shown in Fig. 9. The current limiting of the VSC in constant current mode is shown and the VSC starts to supply the load current in voltage control mode after the arc fault is cleared.

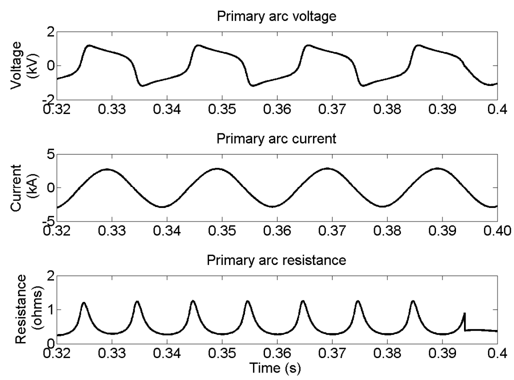

Fig. 6. Parameters during primary arc period

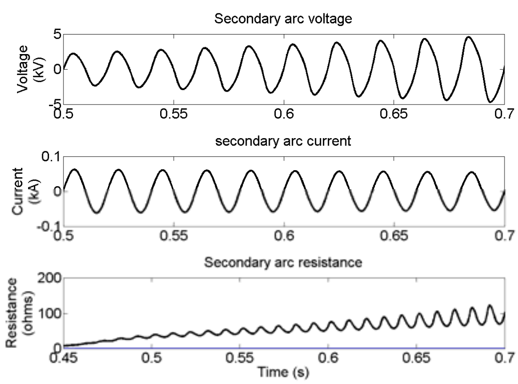

Fig. 7. Parameters during secondary arc period

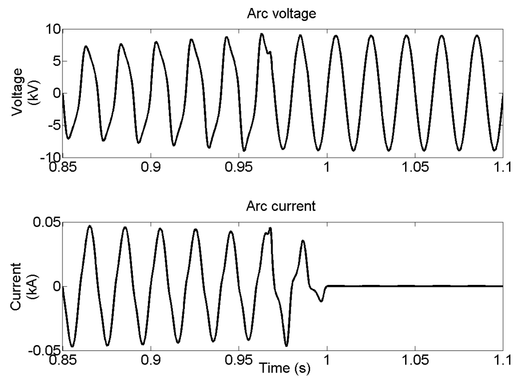

Fig. 8. Parameters during arc extinction

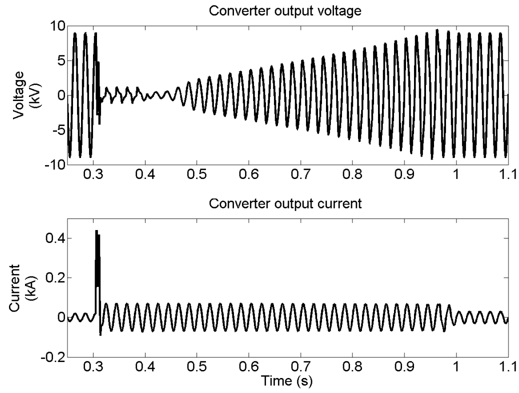

Fig. 9. DG output voltage and current in CC control

B. DG with FBC Control Strategy

In this section, results are obtained by implementing the foldback current control to the converter interfaced DG. Similar to the above case, the arc fault is created at 0.305 s and utility side circuit breaker, CB_1, responds at 0.395 s. The arc voltage and current during the primary arc period are shown in Fig. 10. Results are similar to the case of CC control since only the converter control strategy has been changed and its effect on fault current magnitude is negligible with compare to the utility source current. Fig. 11 shows the voltage at the fault point and arc current variation over total time period of the arc. The arc voltage during the primary, secondary and arc extinction is shown. The arc extinction occurs at 0.430 s. Therefore secondary arc duration can be determined as 0.035 s when VSC is controlled by FBC controller.

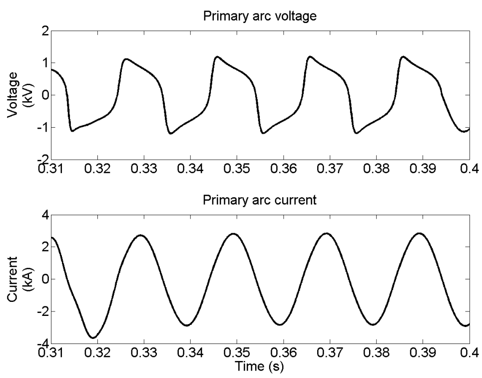

Fig. 10. Primary arc voltage and current

The secondary arc current is separately shown in Fig. 12 since its value is small compared to the primary arc current. It can be seen that fault current supplied by the VSC has reduced due to the foldback characteristic. As a result, fast arc extinction can be achieved. The variation of arc resistance is shown in Fig. 13. According to the figure, sudden increase in arc resistance can be seen just before the arc extinction.

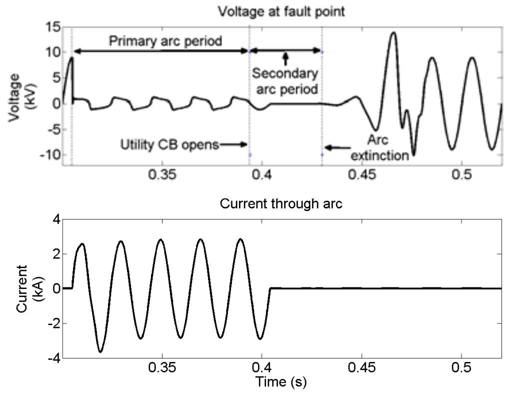

Fig. 11. The variation of arc voltage and current

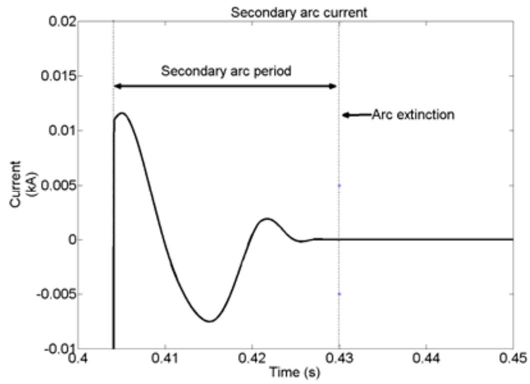

Fig. 12. The variation of secondary arc current with FBC

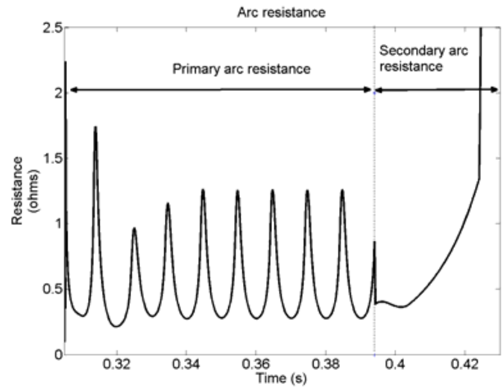

Fig. 13. The variation of arc resistance

The peak current magnitude of the converter in FBC control is shown in Fig. 14. The converter injects nearly 10A of current during the primary arc. However, the output current of converter decreases nearly to zero (the setting can be adjusted) immediately after the utility side breaker opens. As a result of lower arc current, arc extinguishes very rapidly even when the

DG is not disconnected. After the successful arc extinction, the VSC starts to recover along the foldback characteristic. Finally, the VSC fully recovers to the voltage control mode after 0.030 s of arc extinction as shown in Fig. 14.

The terminal voltage of the VSC during the arc fault and the recovery is shown in Fig. 15. The VSC recovers to the normal operation successfully in voltage control mode since load capacity is less than the DG capacity. Arc extinction by means of thermal and dielectric should be considered to get an accurate result. In this study, only the thermal arc extinction has been considered. Therefore, there is a probability to reignite the arc once the VSC is fully recovered to the voltage control mode.

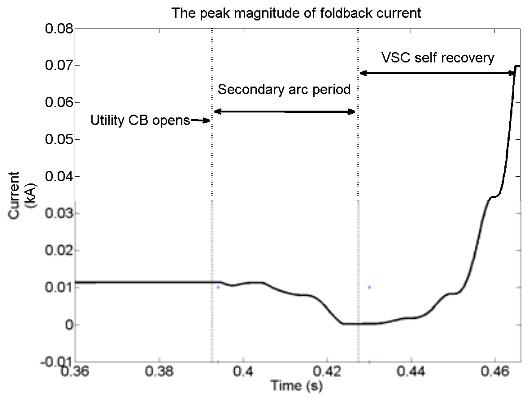

Fig. 14.Peak current injection by VSC in FBC control

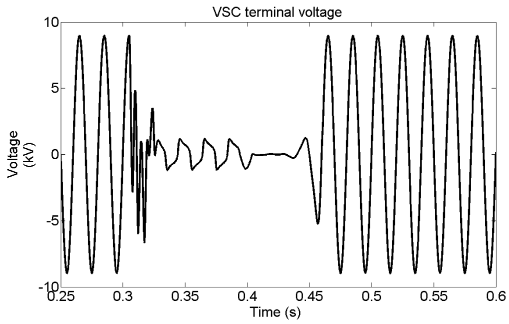

Fig. 15. The variation of VSC terminal voltage during the arc

C. Comparison of Results

The secondary arc extinction time for different control strategies is shown in Table II. Primary arc period is same for both the cases. The DG can sustain the arc after the utility has been disconnected. However, according to the results, the secondary arc extinguishes very quickly if VSC is employed with FBC controller. Therefore, arc extinction can be achieved without disconnecting a DG or DGs, which are controlled by FBC control, in a distribution network. Also FBC control provides the fast restoration of the system if the generation of DGs is sufficient to supply the load demand.

Table II. Secondary arc extinction time

VSC control strategy	Secondary arc extinction time (seconds)
CC	0.610
FBC	0.035

V. CONCLUSIONS

Arc fault analysis is carried out in a distribution network with the presence of converter interfaced DGs. The different control strategies are considered for the converter. Results reveal that the converter with foldback current control has the ability to extinguish an arc fault quickly without disconnecting the converter connected DG from the network. Therefore reliability of the network can be increased. Also foldback control characteristic of a converter can

- self-restore the system if DG generation is sufficient to supply the load demand
- increase the fault ride-through capability of a converter due to the low power dissipation during a fault. As a result, converter can be kept connected to the system for a certain time period without damaging the components of the converter.
- be advantageous to a micro-grid which operates in autonomous mode due to the fast arc extinction and self-restoration

It can be concluded that DG benefits can be maximized by implementing the foldback current control to a converter interfaced DG since it provides several advantages over the existing constant current control.

REFERENCES

[1] L. Kumpulainen and K. Kauhaniemi, “Distributed generation and reclosing coordination,” Nordic Distribution and Asset Management Conference, 2004.

[2] IEEE Std. 1547, “IEEE standard for interconnecting distributed resources with electric power system.”

[3] L. K. Kumpulainen and K. T. Kauhaniemi, "Analysis of the impact of distributed generation on automatic reclosing," Power Systems Conference and Exposition, vol. 1, pp. 603-608, 2004.

[4] V. V. Terzija and H. -J. Koglin, “On the modeling of long arc in still air and arc resistance calculation,” IEEE Trans. on Power Delivery, vol. 19, pp 1012 – 1017, 2004.

[5] A. T. Johns, R. K. Aggarwal and Y. H. Song, “Improved techniques for modelling fault arcs on faulted EHV transmission systems,” Proc. IEEE - Generation, Transmission and Distribution, Vol. 141, pp. 148-154, 1994.

[6] A. I. Megaheda, H. M. Jabrb, F. M. Abouelenina, and M. A. Elbakryb, “Arc characteristics and a single-pole auto-reclosure scheme for Alexandria HV transmission system,” Electric Power Systems Research, vol. 76, pp. 663-670, 2006.

[7] M. Kizilcay and P. L. Seta, “Digital simulation of fault arcs in medium voltage distribution networks,” 15th Power System Computation Conference, 2005.

[8] L. Prikler, M. Kizilcay, G. Ban, and P. Handl, “Improved secondary arc models based on identification of arc parameters from staged fault test records,” 14th Power System Computation Conference, 2002.

.